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16 November 2006

VIA E-MAIL & FEDERAL EXPRESS

Mr. Bruce H. Burcat
Executive Director
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

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DELAWARE P.S.C.

Re: *PSC Regulation Docket No. 57*

Dear Mr. Burcat:

Enclosed please find the original and ten (10) copies of the Docket No. 57 Advanced Metering Report to the Delaware Public Service Commission.

Please contact me if you have any questions or concerns regarding the enclosure.

Respectfully submitted,

James McC. Geddes

Enclosures
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Docket No. 57 Advanced Metering Report to the Delaware Public Service Commission

Prepared by Delmarva Power & Light Company, Division of the Public Advocate, and the Delaware Public Service Commission Staff

November 15, 2006

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PSC REGULATION DOCKET NO. 57

I. Overview

The Federal Energy Policy Act of 2005 ("Act ") of August 8, 2005 was intended to establish a comprehensive, long-term energy policy by providing incentives for traditional energy production, as well as newer, more efficient energy technologies and conservation. The Act requires each state regulatory authority and each non-regulated utility (i.e., marketer or municipality) to conduct an investigation and issue a decision within 18 months as to whether it is appropriate for each utility to offer each of its customer classes, and provide individual customers upon request, time-based meters and communication devices, which would enable their customers to participate in time-based pricing schedules.

In response to increased energy prices and anticipated capacity constraints, there has been a heightened interest by state regulators, utilities and other entities in investigating and implementing ways to provide consumers with electricity pricing options based on changing wholesale costs that enable consumers to alter the timing of their consumption of electricity. Several of these entities have initiated pilot and full scale programs to test and allow customer response to different electricity pricing options. The programs have incorporated "smart meters" or advanced metering systems, to collect individual consumption data and to provide timely price data to consumers, and other enabling technologies, such as direct load control switches to assist consumers in making informed electricity consumption decisions and to reduce consumption of electricity during high priced periods. The Delaware Commission initiated this Docket and proceeding to perform the evaluation required by Delaware State Title 26 § 1008(b)(1)b of EURCSA and EPAct 2005.

This joint report of Delmarva Power & Light Company, Division of the Public Advocate, and the Delaware Public Service Commission Staff ("Working Group") is filed in compliance with Order No. 6912 which required evaluation of the desirability, feasibility and cost effectiveness of requiring advanced metering technology, including time-of-use metering, to be used throughout or selectively in the service territories of Delmarva Power & Light Company ("Delmarva"). The Working Group recommends that an advanced meter pilot be considered by the Commission for implementation within the State of Delaware within 12 months.

Somewhat similarly, Federal law – in the form of 2005 amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA") – directs state utility commissions to consider whether to have regulated electric utilities (and retail electric suppliers) implement a new PURPA standard related to "Time-Based Metering and Communications." The Working Group believes it is unnecessary to require a new PURPA standard at this time.

II. History

On August 8, 2005, the Energy Policy Act of 2005 ("Act") was signed into law. The Act is described by proponents as an attempt to combat growing energy problems and provide tax incentives and loan guaranties for energy production of various types. The Act was intended to establish a comprehensive, long-term energy policy. It provides incentives for traditional energy production, as well as newer, more efficient energy technologies and conservation. As part of the Act, state agencies are required to investigate, but not necessarily adopt, smart metering. Each state regulatory authority and each non-regulated utility (i.e., marketer or municipality) is to conduct an investigation (to be announced within one year of the EPAct 2005) and issue a decision within 18 months as to whether it is appropriate for each utility to offer each of its customer classes, and provide individual customers upon request, time-based meters and communication devices, which would enable their customers to participate in time-based pricing schedules.[1]

The Delaware legislature passed the Electric Utility Retail Customer Supply Act of 2006, 75 Del. Laws ch. 242, in April of 2006 ("EURCSA"), which instructs the Commission to initiate a proceeding to evaluate the desirability, feasibility and cost effectiveness of requiring advanced metering technology, including time-of-use metering, to be used throughout or selectively in the service territories of Delmarva Power & Light

Company ("Delmarva"). Moreover while the language of the State mandate focuses on the feasibility of deploying advanced metering technology, the State provision recognizes that such inquiry encompasses an evaluation of time-based rate structures.[2]

Conversely, while the new Federal standard speaks in terms of utilities offering each customer (within each class) the option of a time-based rate schedule, consideration of that standard necessarily entails exploring the implementation of time-based meters for those utility customers.[3] The deployment of time-based meters and the use of time-based or load-factor rate schedules necessarily go hand-in-hand; one can hardly be effective without the other.

The Commission initiated this docket and proceeding to perform the evaluation required by § 1008(b)(1)b of EURCSA. At the same time, and in the same proceeding, the Commission stated it will concurrently "consider" the newly proposed "Time-Based Metering and Communications" standard under PURPA. While the two directives for this proceeding come from differing sources, and may differ in scope and some details, they share the same focus: a review of the benefits and costs that might flow from the

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[1] State regulatory agencies which have previously considered or enacted smart metering standards within three years of EPAct 2005 are exempt.

[2] See 26 Del. C. § 1008(b)(1)b (in evaluating advanced metering deployment, the Commission "shall review all customer pricing implications of any particular metering technology investigated"). See also 26 Del. C. § 1008(b)(1) (demand-side management programs to be designed "to reduce overall electricity consumption by [Delmarva's] customers and/or to reduce usage by customers during peak periods, such as time of the use rates, advanced metering infrastructure . . ."). However, the 2006 state law amendments seemingly bar the Commission from approving "peak time billing" for use by either Delmarva Power & Light Company ("Delmarva") or the Delaware Electric Cooperative, Inc. ("DEC"). Similarly, the new state law precludes the Commission from permitting use of "30-day peak demand billing" even if time-based metering technology might eventually be deployed. However, in 2006, epilogue language was added stating that "The provisions of 75 Del Laws, c. 242 notwithstanding, the Public Service Commission shall have the authority to implement demand side management programs designed to reduce peak electricity usage. (26 Del. C. § 1008(b)(1)b.)

[3] See 16 U.S.C. §§ 2621(d)(14)(B), (C) (listing types of time-based rate schedules that may be offered in conjunction with provision of time-based meters); § 2625 (i) (time-based rate schedule standard includes investigation into deployment of time-based meters). The Federal standard includes "critical peak pricing" as one of the time-based rate schedules that might be considered. 16 U.S.C. § 2621(d)(14)(B)(ii).

widespread deployment of time-based metering that allows customers to monitor and manage electric consumption.

Currently, Delmarva does provide several time-based rate schedules for customers within its Medium, General, and Large service classifications. Those rate schedules depend on the use of demand, or in some instances, interval metering. Delmarva also now provides "Hourly Priced" (i.e., "real-time" priced) Standard Offer Service to GS-T customers as well as electing GS-P customers. Finally, for several years, Delmarva's tariff has included several time-of-use rate schedules that are available to a small pool of its residential class of customers that utilize time-based meters. Staff reports that, as of now, participation in these time-of-use rate schedules is minimal.[4]

Both the state and Federal directives come with some procedural requirements. EURCSA Section 1008(b)(1)b calls for "hearings" to precede any Commission determination to require any deployment of advance metering technology throughout, or selectively within, Delmarva's service area.[5] PURPA contained its own set of procedural prerequisites that must surround a state commission's determination whether to adopt or reject any Federally proposed standard.[6]

III. Description of Advanced Metering Systems

A. Definition

The Advanced Metering Working Group recommends that the recently developed FERC Staff definition of "advanced metering" be adopted by the Commission in this proceeding. The FERC Staff definition is:

> Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal

[4] As part of the merger settlement approved by PSC Order No. 5941 (Apr. 16, 2002), Delmarva agreed to work with Staff and other interested parties to initiate a pilot program designed to test the efficiency of various metering technologies. The pilot program was put on hold previously in anticipation of a more encompassing advanced metering investigation.

[5] See 26 Del. C. § 1008(b)(1)b.

[6] See 16 U.S.C. §§ 2621(b), 2631 & 2632.

of measurements over a communication network to a central collection point.[7]

B. Benefits

The Working Group discussed the potential benefits of electric utility advanced metering infrastructure systems ("AMI"). A brief description of each of these potential benefits is presented below:

- Remote Meter Reading – capability to read meters remotely.
  - Eliminates need for meter reader to read the meter.
  - Permits more frequent readings.
  - Supports enhanced customer service capabilities such as customer moves, selectable billing dates, and response to high bill complaints.
  - Improves reading accuracy.
  - Discovers malfunctioning meters.
- Demand Response.
  - Potential integration of communication infrastructure with demand response enabling technology.
  - Supports demand response through pricing that more closely tracks market conditions.
  - Can reduce the price of electricity to all consumers by reducing purchases of high priced peak power and to participating customers by reducing peak pricing hedge costs.
- Interval Data Capability (Hourly or Sub-Hourly).
  - Supports time differentiated billing – hourly, critical peak rates, time-of-use rates, etc.
  - Supports demand response activities.
  - Provides additional customer specific load research data.
  - Enhances customer control over monthly bills through additional information regarding electricity consumption.

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[7] (Federal Energy Regulatory Commission Staff Report entitled "Assessment of Demand Response & Advanced Metering," August 2006, p. 17.)

- Distribution System Asset Management.
    - Grid Condition Monitoring – Voltage and Phase Monitoring.
- Outage Reporting.
    - Supports more rapid customer restoration time.
    - Eliminates need for customer outage calls.
    - May lessen utility expense because repair trucks can be dispatched with improved accuracy.
- Remote Service Disconnect.
    - Reduces utility service visits.
- Tamper Detection.
    - Informs utility of possible meter tampering.

The technical capabilities of AMI are evolving rapidly. Suppliers currently offer a variety of systems with differing capabilities. Unfortunately, at this time, no universal standard for the communication protocol for these systems exists. Systems selected today could limit the specific types of meters and demand response enabling technology that could be integrated with the system in the future. Ideally, in the near future, advanced metering infrastructure equipment manufacturers will adopt a standard communication protocol that will support the capability of communicating with many different types of meters and demand response enabling equipment.

C. Meters

A variety of meters is currently available for AMI systems; unfortunately due to the lack of uniformity in AMI communication protocol, limited types of meters are available for each system. The primary issues with meter selection include communication capability and data storage capacity. Meters can collect hourly or more frequent data. The meters will generally be read daily, in part due to data storage capacity limits.

D. Communications

One of the primary components of an AMI is the communication system. At this time, five primary alternative communication methods exist:

- Power Line.
- Broadband Over Power Line.
- Radio.
- Cellular.
- Telephone Landlines.

Communication issues are described more completely in Appendix A.

E. Billing System

Delmarva's current billing system, like most U.S. existing electric distribution company billing systems, does not support an advanced metering system that supplies hourly or sub-hourly energy use data for significant numbers of customers. Additionally, Delmarva's existing billing system is not capable of producing detailed monthly bill statements that delineate energy use and pricing information in a detailed manner. Widespread deployment would require upgrading or replacing Delmarva's existing billing system and accompanying bill printing capabilities to take advantage of the significant quantities of data that would be available through AMI. It would be significantly less costly to Delaware electricity consumers if Delmarva's parent, Pepco Holdings, Inc., develops a new billing system that is shared across its three electric distribution companies. A critical issue in the deployment of AMI is whether to upgrade or replace customer billing systems before or after the installation of the AMI system.

F. Other Utility Systems

Additional software at the utility control center will be required to take advantage of other AMI system capabilities including outage detection management and other electricity system monitoring. Utility daily load settlement systems will similarly require software revisions to accommodate the significantly increased quantity of data.

G. Demand Response Enabling Technology

Demand response enabling technology permits customers to automatically reduce their electricity consumption in response to high market energy prices or other price incentives and high electric demand conditions. Examples of enabling technologies include:

- The direct load control switches installed under Delmarva's Energy for Tomorrow Program, whereby the compressors of central residential air conditioners and electric water heaters can be cycled off (these switches can also be used to control small commercial customer loads).
- Smart thermostat systems capable of reducing residential or small commercial customer air conditioning and heating load.
- Direct interaction with larger customer energy management systems.
- Direct control over specific larger customer electric end-uses.

These technologies can be designed:

- To be integrated directly with the smart metering system.
- To rely on the same communication network, but not be connected to the actual meter, or
- To be operated separately from the smart metering system using a separate communication system.

Enabling technologies clearly foster greater quantities of demand response from residential and small commercial customers as evidenced by the California smart metering experiments. Enabling technologies can be deployed prior to smart meter system installations, in conjunction with smart meter system installations, or after smart meter system installations. Ideally, any future deployment of demand response enabling technologies will be designed to leverage off of one another.

As discussed generally by the Working Group, additional demand response in the Delaware regional electricity market could put downward pressure on electricity prices (including capacity, hedge and energy market prices), provide customers with greater control over their electricity bills, foster greater system reliability, and optimize electric system design.

H. Customer Education and Utility Training

If an AMI system is deployed, customer educational materials must be prepared to explain any changes to customer utility service. In addition, utility personnel must be trained to operate the new system.

I. Deployment Issues

A primary consideration prior to AMI deployment is whether the system will be installed for all customers or only for a limited number of customers. The most cost-effective technique for implementation is the deployment of a system for all utility customers located within a geographic area. Drawbacks to deployment of an AMI system for only a portion of Delmarva customers include: utility meter readers would still be required, outage information would not be universally available, system operational data would not be available for all customers, and billing capability improvements would be only available on a limited basis. Many of the costs associated with AMI deployment are fixed and do not vary with the deployment levels, thus the per participant expense would be much higher with a limited deployment.

J. AMI Costs

It is difficult to determine the exact costs of deploying a Delmarva AMI system in Delaware until the system specifications are developed and equipment suppliers respond to a utility issued RFP. However, Delmarva continues to examine possible AMI deployment and the Company currently estimates that a universal deployment of AMI would cost between $62.5 million and $74.4 million for all Delmarva Delaware customers[8] depending upon system capability and configurations. Upgrading or replacing Delmarva's existing billing system to take advantage of AMI deployment is estimated to cost an additional $15 million[9] (assuming the expense of billing system improvements is shared by PHI's three electric distribution companies). Additional significant expense would be incurred for Control Center software, upgrades to the utility settlement system, customer educational materials, utility personnel training, and any deployed demand response enabling technology. Monthly operational expenses are difficult to estimate

[8] Per customer estimates range between $210 to $250 for universal deployment.

until a specific communication system is selected. Operational expenses would be offset to some extent by benefits such as reduced meter reading costs, reduced outage restoration expense and other operational efficiencies. It is Delmarva's contention that the meters that are replaced will need to be fully amortized net of any residual value when they are removed and recovery of this utility expense will be required within a reasonable time period.

K. Utility AMI Cost Recovery Mechanisms

If widespread or universal deployment of AMI is ordered or approved by the Commission, a utility cost recovery mechanism will be required. The Working Group assumed that Delmarva would be responsible for arranging for the construction of any AMI system for its customers. The significant project costs could be recovered through base electric distribution rates, customer meter charges, a surcharge mechanism, or some combination of these three mechanisms. The Working Group concluded that any AMI deployment would be similar to the provision of other electric distribution core services. Delmarva and other Working Group members noted the importance of ensuring that any amortization period reflects the expected life of the AMI system and that this period of time is likely to be considerably less than thirty years due to the rapidly evolving nature of AMI related equipment and communications. The Working Group also recognized the need to recover costs over a time period commensurate with consumer benefits. .

L. AMI Cost-Effectiveness/Business Case

The Working Group discussed the numerous potential benefits of AMI and whether a traditional cost-effectiveness study is necessary prior to any Commission decision concerning a broad deployment of AMI. (See Benefits section of this report for a description of AMI benefits.) Due to the numerous utility operational improvements that can be attained through AMI, the improved utility customer services that can be provided, the refined wholesale and retail supplier pricing that can be designed and offered, and the improved demand response that can be attained, the Working Group suggests that the Commission consider examining the overall AMI business case rather

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[9] This value is essentially a fixed cost and would not vary by customer participation levels.

than relying upon a traditional cost-effectiveness evaluation. One method of developing and refining this business case could include information gathered through a Delaware specific AMI pilot program.

IV. Delmarva Existing Meter and Tariff Status

A. Delmarva Existing Metering Equipment

Table 1 depicts the type of meters currently installed in Delmarva's Delaware service area. Virtually all of Delmarva's residential customers have standard watt hour meters capable of providing cumulative kilowatt-hour consumption that are read on a monthly basis by a meter reader; approximately 23,580 of these meters can be read remotely. Small commercial and industrial customers have the following meter types: standard watt hour meters capable of providing cumulative kilowatt-hour consumption that are read on a monthly basis by a meter reader, similar meters that also have the ability to measure demand, a very limited number of time-of-use meters capable of recording energy consumption differentiated across three time periods, and approximately 820 meters capable of providing cumulative monthly kilowatt-hour consumption and being remotely read. All large commercial and industrial customers have time-of-use meters capable of providing time differentiated consumption over two periods as well as demand data; 800 customers have 15 minute interval meters which are read on a monthly basis; and 100 customers have meters capable of being read remotely.

Table 1

Delmarva Delaware Meter Types by Customer Group

Customer Group	Non-TOU Energy Only Meters	Non-TOU Energy & Demand Meters	TOU Meters	Interval Meters	AMR Meters
Residential	283,900	0	100	0	23,580
Small C & I	19,900	12,000	100	0	820

Large C & I	0	0	1,500	800	100
Total	**303,800**	**12,000**	**1,700**	**800**	**24,500**

B. Delmarva Rate Tariffs

Delmarva currently has several rate designs for its Delaware residential customers[10]. Most residential customers are served under Residential "R" and Residential – Space Heating "R" tariffs; both of these have seasonally differentiated energy rates for SOS customers but neither has time-of-use differentiation or demand charges. The Delaware SOS residential time-of-use tariff, "R-TOU" provides for daily time-of-use energy rates with two rating periods and seasonally-differentiated demand charges. The similar Residential Time-of-use Non-Demand "R-TOU-ND" has seasonally differentiated daily time-of-use energy rates for SOS customers, but no explicit demand charges. The Residential Time-of-use Super Off-Peak "R-TOU-SOP" tariff has seasonally differentiated daily time-of-use pricing with three rating periods for SOS customers. Approximately 100 Delaware residential SOS customers are served under these daily time-of-use tariffs.

Approximately 20,000 small commercial/industrial customers with maximum monthly energy use below 3,500 kWh are served under the Small General Service-Non Demand tariff, which has seasonally differentiated energy charges for SOS customers. About 12,000 somewhat larger Delaware small commercial/industrial customers (more than 3,500 kWh maximum monthly energy use and up to 300 kW maximum summer monthly demand) are served under the Medium General Service tariff, which has seasonally differentiated demand charges for SOS customers and flat energy charges.

Large Delaware commercial/industrial customers are served under Large General Service (summer monthly maximum demand of 300 kW or greater), General Service-

[10] The Working Group again notes that EPAct 2005 directs the Commission to evaluate whether it is appropriate for each utility to: (a) offer each of its customer classes, and provide individual customers upon request, time-based meters and communication devices, which would enable their customers to participate in time-based pricing schedules.

Primary Rate (for large customers with service at a primary voltage level), and General Service-Transmission Rate (for large customers with service at a transmission voltage level) tariffs. Each of these tariffs for large commercial/industrial customers includes seasonally differentiated demand charges and time-of-use energy charges with two rating periods for SOS customers. Larger commercial/industrial customers may be served under Market Priced Supply Service, which provides for hourly energy pricing and capacity charges based on PJM market prices in the Delmarva Zone.

C. Delaware Rate Design Considerations

There are many rate design variations that could be considered and/or implemented in a demand response program. The Working Group understands that the statutory language prohibits the **implementation** of critical peak pricing. The Group believes that the language in HB6 is specific to widespread implementation of mandatory peak pricing, and that within the framework of a pilot program, all rate design issues can be explored.

V. Delaware Market Acceptance of AMI

The Working Group discussed the market acceptance of AMI in Delaware. Facets of market acceptance include the following:

- Customer reaction to additional customer service capabilities, potential new rate designs, new bill design, ability to better control electricity bills, and potential cost impact of AMI.
- Competitive retail energy supplier willingness to create new energy service offers to take advantage of additional energy consumption data. These offers include customer specific price and variable rate design.
- SOS wholesale supplier willingness to modify future price bids in response to additional data regarding customer energy use.
- Utility ability to maximize benefits of additional operational data.

The Working Group noted that additional information regarding market acceptance would be needed prior to any determination about the appropriateness of a broad-scale rollout. This information could be gathered through a smart meter pilot program, experiences in other jurisdictions, or Delaware market specific information.

VI. Summary of Experience with Advanced Metering Activities in Other Regions

This section of the report explains time-based rates used in demand response programs, and provides a brief overview of recent activities in the United States. Selected pilot and full scale demand response programs are summarized in Appendix B. These programs are designed to incent customers to reduce consumption at times of peak load. They also give customers greater ability to control their electricity costs.

Time-based rates:

Time-based electric rates include Time-of-Use (TOU), Critical Peak Pricing (CPP) and Real-Time Pricing (RTP) or Hourly Pricing (HP). Variants of CPP rates include Critical Peak Rebates (CPR), Fixed-period CPP (CPP-F) and Variable-period CPP (CPP-V) rates.

Under Critical Peak Pricing, a critical peak price applies during the times defined as critical peak periods or events. Electricity prices during the critical peak hours each year will be substantially higher than the conventional retail rates. CPP events may be triggered by system constraints or high wholesale prices. CPP rates can be superimposed on TOU or other rates.

Under CPP, customers typically have two prices: 1) critical peak prices, and 2) prices for all other hours. Critical peak prices will be in effect for a specified number of hours on critical peak days. A limit to the number of critical peak days and hours can be established during program design. Critical peak days may occur during the summer and winter months. Customers are notified prior to a peak pricing event in various ways, such as automated phone call, email, text page, or smart thermostat notification.

Under CPR, customers can earn rebates if they reduce their consumption during critical peak events. The rebate is calculated by comparing the reduced consumption to what the consumer normally uses during the event hours and by multiplying the reduced consumption (measured in kilowatt-hours) by the rebate amount per kilowatt-hour.

A. Experience with Selected Pilot and Full Scale Demand Response Programs

Appendix B provides summary matrices of some of the price responsive pilot programs and full scale programs either offered to electricity customers or in the planning stage in the U.S. and Canada. Smart meter pilots generally test the following pricing options: Critical Peak Price (CPP), Critical Peak Rebate (CPR), and Real Time Pricing (RTP). Many of these projects are designed to measure five primary items: 1) reduction in electricity consumption during peak times, 2) changes in overall consumption, 3) customer satisfaction with different pricing options and technologies, 4) usefulness of the selected technologies, and 5) the value of presenting additional pricing information to customers.

The Federal Energy Regulatory Commission (FERC) 2006 Staff Report, "Assessment of Demand Response & Advanced Metering," [11] reported that only 259 of the 2,620 survey respondents offered time-based rates in 2005 in the U.S. The time-based rates offered were Time-of-Use (187 entities), Real-Time Pricing (47 entities), and Critical Peak Pricing (25 entities). Investor-owned utilities accounted for the bulk (85%) of the residential customers enrolled in TOU tariffs. The top five entities with the largest number of residential customers enrolled in TOU programs were: Pubic Service Company of Oklahoma, Arizona Public Service Company, Salt River Project, Southwestern Electric Power Co. and Pacific Gas and Electric Company. The report noted that "many of the CPP tariffs appeared to be pilot programs (e.g., utilities that participated in the California Statewide Pricing Pilot)." The top five entities by number of customers enrolled in CPP programs were: Gulf Power Company, Cass County Electric Cooperative, Southern California Edison Company, San Diego Gas and Electric and Pacific Gas and Electric Company.

[11] This report is summarized in Appendix C.

VII. Delaware Specific Smart Meter Pilot Program Discussion

The Working Group discussed the significant costs and work involved in the implementation of an AMI system, the uncertain market acceptance of a wide-scale rollout of an AMI system, the rapidly evolving technology, and the great interest in new customer options to better manage energy costs. Based in large part on the above analyses, the Working Group focused more specifically on the benefits of establishing a smart meter pilot program in Delaware during 2007. The benefits of a Delaware smart meter pilot project include:

- Direct Delaware electricity market stakeholder experience with the capabilities of AMI prior to any decision on a broad-scale rollout.
- The ability to obtain Delaware specific residential and small commercial customer market data concerning customer price response.
- An opportunity to test customer receptivity to alternative electricity pricing mechanisms, bill format, and accompanying demand response enabling; and technology.
- A near-term opportunity for pilot participants to gain additional control over their monthly electricity bills using new technology.

The Working Group discussed the design components of a possible smart meter pilot program in Delaware. These elements included the following key items: 1) number of participants, 2) customer class, 3) customer energy supplier type participation, 4) voluntary vs. involuntary participation, 5) participation incentive, 6) geographic location, 7) participating entities in pilot design/operation, 8) demand response enabling technology, 9) pilot duration and timeline, 10) rate design, 11) pilot billing, 12) pilot AMI characteristics, 13) evaluation considerations, 14) pilot cost, and 15) pilot funding mechanism. Working Group members reached the following general agreements regarding each of the key design elements:

- Number of Participants – 250 participants, assuming this value establishes statistical validity.

- Customer Class – Primarily residential, could include small commercial customers if sufficient funding is available.
- Customer Supplier Type Participation – SOS supplied customers only.
- Voluntary participation by invitation, drop outs permitted.
- Participation incentive recommended.
- Geographic Location – restricted area would help to minimize project cost and simplify participation recruitment; however, advantages of participation throughout Delaware were recognized. Additional utility distribution benefits could be studied if participants were congregated on specific distribution feeders.
- Participating Entities – Delmarva, Commission Staff, Public Advocate.
- Demand Response Enabling Technology – Deployed pilot technology could include a mixture of smart thermostats and some method of communicating price information to customers. RFP should be issued to determine technology options.
- Pilot Duration/Timeline – Two years beginning in 2007. Two years mitigates variations in weather.
- Rate Design – One or more critical peak pricing rates pegged to PJM market Locational Marginal Price for Delaware portion of Delmarva PJM Zone.
- Pilot billing – most likely provided by a third party billing entity due to small scale of pilot. Fixed costs likely to be too high for use of Delmarva billing system for pilot.
- AMI characteristics – RFP should be issued to AMI vendors for best solution at a reasonable cost.
- Evaluation considerations – Market research, process and impact evaluations to be conducted. Interim evaluations would consider accelerated or stepped future broad scale AMI roll out.
- Pilot cost – Actual pilot cost can only be determined after all components of pilot are designed and responses to vendor RFP's are received. It is anticipated that the costs of a pilot on the scale of 250

participants would not exceed $1 million, but pilot costs will vary widely depending upon final design and the $1 million maximum cost is a rough estimate. By way of comparison, the costs of Pepco's smart meter pilot project for 2,000 customers are expected to be approximately $2 million. Pilot costs are not indicative of full-scale rollout expense.[12] Notably many pilot costs are relatively fixed regardless of the number of participants.

A. Pilot funding

Delmarva's position is that the merger Settlement Agreement[13] requires Delmarva to work to develop a 250 point pilot, but does not provide funding to support such a pilot. Delmarva recommends that a nonbypassable customer distribution surcharge be established by the Commission to recover pilot costs over the duration of the pilot. Public Service Commission Staff recommends that the cost of the pilot (design and implementation) be borne by both the Company and customers. Staff recommends that the Company's contribution be capped at $250,000 and that customers be responsible for

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[12] Vendors could under price their equipment and services to break into the market or charge higher prices in recognition of the small scale and short duration of the pilot

[13] On April 16, 2002, the Delaware Commission issued Order No. 5941 approving the merger of Delmarva and Pepco and the proposed merger settlement agreement ("Settlement Agreement") agreed to on November 30, 2001. The Settlement Agreement provides, in part, that:

> Delmarva agrees to work in good faith with Staff and other interested parties (whether part of this proceeding or not) to initiate a pilot program for approximately 250 residential or small commercial customers that would test the appropriateness of larger-scale initiatives or offerings with respect to real-time metering or advance-pay metering, or other similar metering technologies. (Paragraph I.3)

Delmarva's contention is that the Company did not agree to provide any financial contribution to support of the development and implementation of such a pilot program and accordingly, there is no such commitment in the approved Settlement Agreement. Therefore, if a smart metering pilot program is implemented in Delaware by Delmarva, the Commission must establish a funding source for any pilot related expenditure.

In response to the Settlement Agreement, Delmarva representatives met on numerous occasions with the Commission Staff, and representatives of the Public Advocate to discuss a possible Delaware smart metering pilot. A summary of these activities is contained in Appendix D.

the remaining cost. Staff recommends that a nonbypassable customer distribution surcharge be established by the Commission to recover pilot costs above the Company's portion over the duration of the pilot. The Division of Public Advocate is opposed to customers paying one hundred percent of the pilot costs. The DPA believes that the company will benefit the most from the data that the pilot program will generate with regards to load characteristics. In addition, the DPA believes that these costs should be presented for possible recovery from customers in a rate case, not a surcharge. However, in our ongoing effort to work cooperatively, and in order to move this docket along in a manner consistent with that of a working group concept, DPA would ask that if a cost sharing proposal is adopted by the Commission for recovery of the pilot program costs, that it be the customer contribution that has a fixed cap, not Delmarva's, in order to provide an incentive for the company to keep these costs reasonable.

VIII. Recommendation

The Working Group has concluded that the deployment of an AMI system by Delmarva could provide significant benefits to Delaware electricity consumers. These benefits could enhance utility customer service and utility distribution operations. Additionally, AMI and an accompanying upgrade of utility billing capabilities could provide customers with greater control over their monthly electricity bills by providing additional information and encouraging demand reductions during high priced periods. These reductions would be expected to exert downward pressure on wholesale electricity market prices over the long-run. However, the Working Group notes that any deployment of AMI and an accompanying upgrade of Delmarva's billing systems is costly and complex. Therefore, the Working Group is unable to recommend the universal deployment of AMI by Delmarva at this time until additional information is available.

The Working Group believes the Commission can address the requirements in the Federal and State legislation by doing one of the following:

- Create pilot.
- Study pilots and full scale programs going on elsewhere.

- Conclude that no action is required.

The Working Group believes that if the Commission elects to implement a pilot AMI program that this pilot would permit Delaware to explore and test the advantages without having to incur the costs of a full scale AMI deployment. AMI offers significant opportunities for improvements in utility operations in remote metering reading, demand response, interval data capability, distribution system asset management, outage reporting, remote service disconnect and connect, and tamper detection. The Working Group members recommend that if the Commission establishes a pilot that there be a pilot program development group comprised of Delmarva, Commission Staff, and the Public Advocate.[14] That working group should be directed to submit a specific pilot program design to the Commission for its approval by June 1 2007, for implementation during the third and fourth quarters of 2007. The proposed design should include all project elements, including recommended metering and demand response enabling equipment, communications systems, and recommended rate design.

It should be noted that there are several disadvantages of pilot smart metering programs including: 1) cost, 2) potential delay of full deployment of AMI pending full pilot evaluation, 3) statistical validity issues, and 4) that the deployed technology and billing systems are unlikely to be identical to the ones used in a broad scale AMI deployment. An alternative to relying upon a Delaware specific pilot to gather intelligence to enhance future decisions regarding demand response and smart metering opportunities would be to conduct a thorough examination of other recent smart meter pilot programs and full-scale deployments. Many of these recent activities are described in Appendix B of this report. Information such as demographics, geography, and customer market research from other programs could be combined with Delaware specific information to enhance insights into the potential impact of an AMI project in Delaware.

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[14] Other entities that have expressed an interested in participating in the implementation of a pilot program include U.S. Senator Carper's Office, Pacific Northwest National Laboratory, the University of Delaware, and the PJM Interconnection, L.L.C. To the extent that these other entities are able to provide additional funding or technology or expertise, their participation should be considered.

However, notwithstanding these disadvantages, the Working Group believes that a properly designed pilot program could provide the parties and the Commission with useable and reliable information as to the potential benefits from a more universal AMI deployment in Delaware. It is Staff's view that a pilot program will fulfill the commitment made at the time of the PEPCO merger to initiate a program to test the advantages of various metering technologies and is the natural outcome of the EURCSA legislation that instructed the Commission to investigate the desirability, feasibility and cost effectiveness of requiring advance metering technology.

A

Appendix A – Communication Considerations

The primary component of an AMI is the communication system. At this time, five alternative communication methods exist, power line communications, broadband over power line, radio, and systems using cellular and/or landlines. Under power line carrier, data pass through the electric distribution network and are gathered at electric distribution substations for transmittal back to the utility. Broadband over power line ("BPL") permits a greater quantity of digital data to be passed through the electric distribution network; however, the data are filtered by utility transformers necessitating the installation of equipment to bypass each transformer. BPL systems are more expensive to install than other AMI communications systems due to the additional required equipment. Delmarva's sister utility, Pepco, has participated in a BPL test in Montgomery County, Maryland for several years. Radio based systems directly communicate with individual meters. Mesh systems permit meters that are unable to directly communicate with the radio tower due to interference to communicate with nearby meters that have the capability of passing data to the towers. As an alternative radio communication technique for difficult-to-communicate meters is the installation of additional antenna or special data collectors that have the capability of communicating with the towers. A radio communication system has been selected for Pepco's smart meter pilot program in the District of Columbia. Cellular or landline systems typically rely on available communication networks established by cellular telephone companies and hard-wired telephone systems. The limitations of these systems include monthly access fee expense, rapidly changing cellular communication protocols, and cellular service coverage limitations.

Any deployment of advanced metering infrastructure could include one or more of these communication systems. For example in Delaware, a Delmarva AMI deployment might rely upon a radio system in densely settled urban areas and power line carrier in more sparsely settler rural areas where radio coverage is more limited.

A key AMI deployment decision will be the installation of a one-way vs. two-way system. A one way communication system allows the customer's meter to send information to the AMI system. A two way communication system adds communication from the AMI system to the consumer. The advantages of two-way communications include the following capabilities: remote turn on/off, the ability to send price signals directly to customers, the ability to verify power restoration, and the ability to verify directly connected demand response enabling technology. The considerable operational advantages related to the installation of a two-way system will have to be compared to its greater expense.

B

Appendix B. Summary of Selected Price Response Initiatives:

PILOT PROGRAMS

Utility/State Program Name	Pricing Options	Voluntary or Mandatory	Customer Type/ Participant Level	Enabling Technology	Maximum Customer Price ($ per kWh)	Peak Load Reduction (kW)	Percent Reduction	Operational Timeline	Status/ Comments
California Statewide Pilot	TOU Critical Peak Pricing/Fixed and Critical Peak Pricing/Variable	Voluntary	Residential and small commercial. 2,500 customers statewide	Yes Smart meters. Smart thermostats for customers on CPP-F.	$0.77/kWh at CPP-V super-peak.	Conclusion of Pilot (SPP): Critical peak pricing rates can, within 5 years, reduce California's peak load by 1,500 to 3,000 MW.	Varies by report. From a report for 2003 by members of the California Energy Commission: TOU: 14% CPP-F: 12% CPP-V: 40%	2003 and 2004	The vast majority of customers have stayed on new rates after pilot even though incentives were discontinued and they are now paying a monthly meter charge of $3 - $5.
Anaheim Public Utilities - CA	All customers have tiered pricing: $0.0675/kWh up to monthly baseline of 240 kWh. Beyond baseline rate: $0.1102/kWh. Pilot: Critical Peak Rebate for reducing consumption at critical peak	Voluntary	Residential and small business. 123 Residential	Yes Smart meter.	Rebate of $0.35/kWh reduction		12%	Started in summer of 2005.	Maximum of 12 critical peak pricing days per year. Customers notified day before event. Consumption between noon and 6 PM priced at $0.35/kWh on critical peak pricing days. Consumers credited for difference between reference peak load and actual load during peak hours. Customers guaranteed not to pay more than they would under conventional tariff. June - Oct 2005: Customers received rebates ranging from $50 to $100 for the summer.
SMPPI, Inc. - DC ***SmartPowerDC™***	Hourly Price Critical Peak Price Critical Peak Rebate	Voluntary	Up to 2000 Residential treatment customers 250 residential control customers	Yes Smart meter. Smart Thermostats for approx. half of the treatment customers.	Hourly price: $1.54 cents per kwh CPP: 68 to 69 cents per kWh CPRebate: Res - 56 cents/kWh Res RAD* - 65 cents/kWh			2-year pilot	Pilot created as part of the Pepco merger settlement agreement with Pepco funding of $2 million. Tariff filed 6/1/06 now pending DC Commission approval. Meter was approved 9/21/06.

Pilot (con't) Utility/State Program Name	Pricing Options	Voluntary or Mandatory	Customer Type/ Participant Level	Enabling Technology	Maximum Customer Price ($ per KWh)	Peak Load Reduction (kW)	Percent Reduction	Operational Timeline	Status/ Comments
Commonwealth Edison - IL ***The Chicago Experiment***	Real-time (Hourly Price with price cap)	Voluntary	Residential over 1,500 enrollments (1,127 in 2006)	Yes Interval meters; no smart meter. Smart Thermostats. In addition, 60 participants received central air conditioning cycling switches.	$0.50/kWh cap. Maximum actual price: $0.352/kWh in 2006.		In 2003: 20%	Pilot 2003 - 2006.	Ongoing. The pilot progream has been successful.In 2006, Illinois General Assembly unanimously mandated that utilities provide residential customers access to real-time pricing (municipals and rural co-operatives exempted). Price Elasticity: In 2003: -4.2%; In 2004: -8.0%; In 2005: -4.7%.
Pepco - MD	TBD**	TBD	Residential and Small Commercial	TBD	TBD	TBD	TBD	TBD	Program proposal to be filed with the MD Commission in 2006.
PPL Electric Utilities - PA ***Demand Side Response Pilot Program - Residential***	TOU	Voluntary	Residential 300 customer limit	No	Sum 2006: 0.090 Sum 2007: 0.091	No estimates done	No estimates done	Began 2005. Residential pilot and tariff ends 9/30/2007.	On average, residential customers save about $300 on their bill in energy capacity. Currently, no customers are under the Demand Side Initiative (experimental) tariff for existing and new commercial/industrial customers (≥1000 KW max demand) to adjust their load requirements in response to market prices of energy–pilot and tariff ends 1/1/2008. AMR is in place for all customers.
PSE&G - NJ ***myPower Pilot Program***	TOU with CPP	Voluntary	1350 Residential treatment customers 450 residential control	Yes Smart thermostat-800 select customers	$0.80 per kwh	No estimate yet	No estimate yet	2005-2006	Results being reviewed. Improvement on similar existing "Cool Customer" program. Additional 100 residential and 95 GLP participants get 2-way direct load control devices.
Puget Sound Energy - WA	TOU	Mandatory with opt out	300,000 residential	Automated meter reading	peak to non-peak differential = 30%		5% reduction in peak demand	May 2001 to November 2002	Pilot terminated abruptly when spread between peak and non-peak reduced
Ontario Smart Meter Pilot Project	CPR over TOU CPP over TOU	Voluntary	400 Residential	Smart meter	CPR: Rebate of $.30 per kWh reduction CPP: $0.30 per kWh	No estimate yet	No estimate yet	2 months 2006 summer 2 months 2006 winter	Ongoing.

*SMPPI/ DC: "Res RAD" is the rate for residential low income customers in the District of Columbia. **TBD - To Be Determined

Appendix B. Summary of Selected Price Response Initiatives:

FULL SCALE PROGRAMS

Utility/State Program Name	Pricing Options	Voluntary or Mandatory	Customer Type/ Participant Level	Enabling Technology	Maximum Customer Price ($ per kWh)	Peak Load Reduction (kW)	Percent Reduction	Operational Timeline	Status/ Comments
Pacific Gas & Electric - CA ***SmartMeter™***	Critical Peak Price	Voluntary	Residential	Yes Smart Thermostats	60 cents plus regular rate.	Not started yet	Not started yet		Program is still in the beginning stages of their AMI rollout. CPP rate has been approved by CPUC. Typically a CPP event would occur only on the hottest days of summer. Estimated $1.74 billion to deploy the new SmartMeter™ technology throughout PG&E's service territory. The Statewide California Energy Plan mandates that 5% of system peak be met through energy efficiency, conservation and demand response.
San Diego Gas & Electric - CA	Critical Peak Rebate	Mandatory with opt out	Plan is for 1.4 million residential electric customers	Solid state meters with communications capability		360,000 kw forecast for 2010. Residential is 176,000 of this amount.		Just finished 3 weeks of hearings. Expect final decision in February 2007 and deployment 2008 - 2010.	No loss for consumer. Consumer gets lower of current tiered bill, or bill based on dynamic pricing.
Gulf Power - FL ***Good Cents***	TOU and Critical Peak Price	Voluntary	Residential with central A/C and landline telephone/goal of 3000 for 2006	Yes Smart Thermostat, Advanced meter, 2 way communication, water heater and pool pump timers	$.326/Kwh, critical peak	2 kW overall, Higher in winter		Full scale program offered since 2001, preceeded by 2-year pilot with 200 customers.	Customers pay $4.95/month to be in program. Fee includes free smart thermostat, smart meter with communication technology and also free surge protection and automatic outage detection. Customers save ~ 15 % on their annual energy bill. May expand into multi-family housing in 2006.

Full Scale (con't) Utility/State Program Name	Pricing Options	Voluntary or Mandatory	Customer Type/ Participant Level	Enabling Technology	Maximum Customer Price ($ per kWh)	Peak Load Reduction (kW)	Percent Reduction	Operational Timeline	Status/ Comments
Ontario Government - Canada ***powerWISE*® (6 major electric utilities)**	TOU	Mandatory	All bundled customers with smart meters	Smart meters. No Smart Thermostats	Peak price is $0.105 per kWh (low period price is $.035/kWh)	No estimates done	Target is to reduce peak demand by 5% by 2007.	Scheduled to begin in 2007.	Program has not begun. Targets set for the installation of smart meters: 800,000 by 12/31/2007 for homes and businesses; and for all Ontario customers by 12/31/2010. Ontario Energy Board has not yet confirmed the mandatory start date for TOU rates.
Toronto Hydro - Canada ***Peaksaver***	Not applicable	Voluntary	Residential, small business and commercial customers are eligible. Currently 30,000 customers particpate.	Switch attached to air conditioner, electric water heater and pool pump.	Not applicable	About 1.2 kW per residential participant.	Less than 1% currently. Target: 2.5% for residential and commercial sectors.	Program began in November 2005.	Interrupts power during peak periods. $25 incentive to join program and possibility for modest prize. Enrollment level high-- 30,000 customers out of potential 50,000.
Hydro One - Canada ***Smart Thermostat***	Not applicable	Voluntary	Residential customers in York area. Businesses also eligible if their air conditioners and electric water heaters are about the same size as residential. About 2,000 thermostats installed to-date.	One-way programable thermostat that will receive set-back instruction.	Not applicable	Average of about 1.2 kW per residential participant over four hour duration of event.	Minimal because program is so new.	New program. Installation began August 2006.	Enrollees get free installed thermostat, 2 CFLs, and installed hot water tank wrap for electric water heaters.

C

Appendix C – FERC Report Summary

Assessment of Demand Response and Advanced Metering
August 2006 Federal Energy Regulatory Commission Report

EXECUTIVE SUMMARY

Introduction

EPAct 2005 required the Federal Energy Regulatory Commission (Commission) to issue a report on demand response resources and advanced metering, and to address certain specific questions. The resulting August 2006 report addresses issues of interest to Delaware.

FERC staff believes demand response deserves serious attention and "encourages states to continue to consider ways to encourage demand response at the retail level" and to work cooperatively with FERC.

In summary, the Commission found that in most regions of the country there is a potential reduction in peak demand of 3-7% from existing demand response resources. Technologies, such as advanced metering, have little market penetration. Experiences in New York, Georgia, California and other states, indicate that customers do adjust their consumption in response to programs, and price. While demand response has the potential to reduce the need for new transmission, it has generally not been considered as a resource during planning. According to the report, the variance in cost/benefit analyses makes it difficult to compare proposals and thus to make judgments about advanced metering.

A more detailed discussion of the report is attached to this Executive Summary.

Key Points

Definition of demand response: For purposes of the report, staff defined demand response to include the categories of incentive-based demand response and time-based rates **but not** energy efficiency measures.

Answers to Questions Mandated by Congress:

What is the level of saturation of advanced metering devices and technologies?

Currently about six percent of installed electric meters in the United States are advanced meters; this level varies across region. The Reliability*First* Council (RFC), which includes Delaware, has the highest penetration rate at 15%, with Pennsylvania at 53%. Delaware, however, has only 12 out of 416,518 advanced meters; its penetration rate is essentially zero.

What demand response programs already exist, and how much do they contribute?

About 5% of customers are on some form of time-based rates or incentive-based programs. For the RFC region, the existing potential is about 4% of peak summer demand; approximately 14% of this potential comes from the residential market, which translates to 0.6% of total potential.

What is the potential for demand response as a quantifiable, reliable resource for regional planning purposes?

Demand response can serve as a local peaking resource and reduce or defer new transmission or distribution facilities. It can also serve as operating reserves. It can increase the utilization of existing transmission, which could provide energy from lower cost generation. While demand response is implicitly considered in regional resource planning, the explicit use of demand response as an alternative to transmission is rare.

PJM, along with the Bonneville Power Administration and the Midwest ISO, reported having policies to consider demand response in transmission planning, but no demand response projects have yet resulted from the policies.

Commission staff recommends that transmission planners and state and Federal regulators assure that the capabilities of demand response are properly recognized. The Commission recommends consideration of the following steps: allowing demand response alternatives to be considered for all transmission enhancement proposals, accommodating the characteristics of demand response, and assuring that requirements are specified in terms of the functional needs, rather than the technology that is expected to fill the need.

What steps have been taken to ensure that demand response receives equitable treatment as a quantifiable, reliable resource for regional transmission planning and operations?

Commission staff identifies a number of steps that could be taken to ensure equitable treatment of demand response in planning and operations. These include steps such as assuring that demand response capabilities are properly recognized and that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need.

What are the barriers to improved customer participation in demand response?

Key barriers include the disconnect between retail pricing (generally flat) and wholesale markets (prices fluctuate), and utility disincentives that occur because reductions in customer demand reduce utility revenue. Without policies to align utility interests with demand response programs, utilities lack incentive to support demand response, especially in light of the uncertainty of cost recovery for demand response initiatives. Restructuring has added disincentives for distribution companies where the distribution utility does not have a direct load responsibility, and the lack of clarity on cost-effectiveness methods is also an issue. In addition, there are state-level barriers such as California and New York laws that limit the introduction of new time-based rates. One commentator interpreted the rate phase-in of Delaware's HB 6 to contain a similar restriction.

Conclusion

Commission staff concludes that demand response has an important role to play in both wholesale and retail markets, and that demand response deserves serious attention. Both the Commission and states should work to encourage demand response.

Assessment of Demand Response and Advanced Metering August 2006 Federal Energy Regulatory Commission Report

I. Introduction

EPAct 2005 required the Federal Energy Regulatory Commission (Commission) to issue a report on demand response resources and advanced metering, and to address certain specific questions. The resulting August 2006 report addresses issues of interest to Delaware.

The Commission's report summarizes its findings. In most regions of the country, the report notes, there is a potential reduction in peak demand of 3-7% from existing demand response resources. Technologies, such as advanced metering, have little market penetration. Experiences in New York, Georgia, California and other states, indicate that customers do adjust their consumption in response to programs, and price. While demand response has the potential to reduce the need for new transmission, it has generally not been considered as a resource during planning. According to the report, the variance in cost/benefit analyses makes it difficult to compare proposals and thus to make judgments about advanced metering.

FERC staff believes demand response deserves serious attention and "encourages states to continue to consider ways to encourage demand response at the retail level" and to work cooperatively with FERC.

This report provides background on demand response, including its benefits and the role of enabling technology, and summarizes the Commission's key findings on the questions mandated by Congress. Mandated questions are as follows:

- What is the level of saturation of advanced metering devices and technologies?
- What demand response programs already exist, and how much do they contribute?

- What is the potential for demand response as a quantifiable, reliable resource for regional planning purposes?
- What steps have been taken to ensure that demand response receives equitable treatment as a quantifiable, reliable resource for regional transmission planning and operations?
- What are the barriers to improved customer participation in demand response?

II. Background

Definition of demand response: For purposes of the report, staff defined demand response to include the categories of incentive-based demand response and time-based rates **but not** energy efficiency measures.

Incentive-based demand response programs include programs such as direct load control, interruptible/curtailable rates and emergency demand response programs. They offer payments to customers to reduce their electric use during times of system stress.

Time-based rates include time-of-use rates, critical-peak pricing, and real-time pricing.

According to the report, the "crux of demand response that this definition addresses is that it is an active response to prices or incentive payments. The changes are designed to be short-term in nature, centered on critical hours during a day or year when demand is high or when reserve margins are low." Demand response, thus, can dampen the severity of price spikes, and can be an important tool to address shortages and help customers manage their electric costs. Some energy efficiency may be achieved over the long term as customers take action to reduce their consumption overall.

Role of demand response in retail and wholesale markets: The report notes that a small percent of customers responding to demand response programs can have a large impact on the market. One study, for example, found that "only a small fraction of all customers, perhaps as few as five percent, are needed to discipline electricity market prices." The downward pressure on prices can be significant. The Demand Response and Advanced Metering Coalition (DRAM) suggests that markets without demand response tools use more power than they need to, and that demand response can be a faster-track solution to relieving areas of constrained supply.

Benefits of demand response: Demand response benefits include decreases in price spikes and volatility, reduced need for additional generation, transmission and distribution and improved system reliability. There are additional benefits of demand response that are harder to quantify, including the hedging of price risks, and tools for customers to manage load. The price responsiveness of demand response can limit the potential for market abuse (such as capacity withholding). Demand response can also link retail and wholesale markets through greater customer price responsiveness to wholesale price changes.

Evidence of customer price responsiveness: In order for customers to respond to prices, they must have time-based rates that are communicated to them, load control systems that allow them to respond to price signals, and meters that measure usage at least by time of day. Experiences in New York, Georgia, California, and other states demonstrate that customers do respond to price signals by reducing consumption. In an experiment in California, for example, small residential and commercial customers reduced load by 13 percent on average and as much as 27 percent, when price signals were coupled with automated controls such as controllable thermostats.

Role of enabling technology: Technologies to support demand response programs include, among others, meters that record usage on a frequent basis such as hourly, smart thermostats that adjust room temperatures automatically in response to price changes or remote signals from system operators, and communication pathways to notify customers of load curtailment events.

III. Advanced metering and market penetration

The Commission conducted an extensive survey and determined that advanced metering had achieved a relatively low penetration of about six percent in the United States electric meter market by the end of 2005.

Definition of advanced metering: Advanced metering is a metering system that records customer consumption hourly or more frequently and provides for daily or more frequent transmittal of measurements over a communications network to a central collection point. Advanced metering, thus, refers to the full measurement and collection system, including customer meters, communication networks, and data management. This full system is commonly referred to as advanced metering infrastructure (AMI).

Overview of AMI: AMI provides value to utilities including not only support for demand response programs, but also enhancement of customer service, reduction of theft, improvement of load forecasting, monitoring of power quality and management of outages. In particular, AMI supports implementation of time-based rates, but not all utility representatives believe the added expense of advanced metering is needed to support time-based rates; rather, they believe that time-of-use meters are sufficient to achieve benefits.

Estimates of advanced metering market penetration from FERC survey: Currently about six percent of installed electric meters in the United States are advanced meters; this level varies across region. The Reliability*First* Council (RFC), which includes Delaware, has the highest penetration rate at 15%, with Pennsylvania at 53%. Delaware, however, has only 12 out of 416,518 advanced meters; its penetration rate is essentially zero.

Utility meter reading, customer service, asset management and outage management benefits: Implementation of AMI "can significantly reduce meter reading expenses and capital expenditures, and can also increase the accuracy and timeliness of meter reading and billing." AMI can "provide important information to assist in electric utility asset management...Proper sizing of equipment, based on detailed and accurate data on customer demand and usage patterns can be a sizeable benefit for some utilities." AMI provides outage management benefits; crews can check for additional problems before leaving a repair area, and can verify outages before dispatching a repair truck. Thus the savings associated with meter reading are only a part of the benefits that can be achieved from AMI.

Costs and benefits associated with advanced metering: The total capital cost of deploying AMI has not declined significantly. AMI costs may range from \$1.25 to \$1.75 per customer per month, measured over the life of the hardware and including both capital and operating costs. According to one source, AMI benefits can amount to \$1.35 to \$3.00 per customer per month. Recent analyses of the business case for AMI have used a variety of costs and benefits in their assessments, making comparison of proposals and judgments on whether to deploy AMI difficult.

Advanced metering and price responsive demand response networks: "With advanced metering, utilities can offer customers a variety of time-base rates, either charging higher prices when wholesale prices are high or offering rebates when customers reduce energy consumption during times of high prices..." California is considering revising its building code to require use of smart thermostats. The SmartPowerDC pilot program in DC will provide customers with a daily bill update.

IV. Existing demand response program and time-based rates

The survey found that use of demand response is not widespread; only about five percent of customers are on some form of rate-based or incentive-based program. For the RFC region, the existing potential is about four percent of peak summer demand; approximately fourteen percent of this potential comes from the residential market, which translates to less than one percent of total potential. The most common demand response programs offered are direct load control programs, interruptible/curtailable tariffs, and time-of-use rates.

Incentive-based demand response programs: These programs include an incentive for customer participation. Examples of these programs include direct load control, interruptible/curtailable rates, capacity-market programs, demand bidding/buyback programs and ancillary services.

Direct load control (DLC) programs include those that cycle appliances such as air conditioners and water heaters off at times of peak load. They also include smart thermostats which can be used to remotely adjust the temperature settings in a house.

Customers on interruptible/curtailable rates receive a discount or bill credit in exchange for agreeing to reduce load during system contingencies. Typically these customers must respond within 30 – 60 minutes of being notified by the utility. Tariffs may be structured such that curtailment is mandatory or voluntary. The report notes that there is a concern among resource planners about whether interruptible/curtailable tariffs provide a reliable resource, and the number of customers taking these tariffs has dropped in the last decade.

In capacity-market programs, customers commit to providing pre-specified load reductions when system contingencies arise, and are subject to penalties if they do not curtail as directed.

In demand bidding/buyback programs, customers offer to provide load reductions at a price at which they are willing to be curtailed. There is an ongoing controversy over the issue of who is responsible for the costs associated with successful bids, particularly in PJM, where discussions continue to determine the size of the incentive provided in PJM's Economic Program.

Finally, ancillary service market programs allow customers to bid load curtailments as operating reserves. PJM began allowing demand response to provide synchronized reserves on May 1, 2006.

Time-based rate programs: These are the second type of demand response program.

Utilities buy electricity at varying prices including peak prices on the spot market. Consumers, however, generally pay a flat rate--an average rate. Economists argue that this flat rate leads consumers to over consume, relative to an optimally priced system, at times of higher prices, and under consume at times of lower prices. They argue in favor of time-based rates that can link wholesale and retail markets.

Time-based pricing includes time-of-use (TOU) rates, critical peak pricing (CPP), and real-time pricing (RTP). These rates expose customers to varying levels of risk; TOU is the lowest, RTP is the highest.

Time-of-use rates are rates differentiated by peak and off-peak periods. Examples of TOU experience include:

- Government experiments from 1975 – 1981 found an estimated elasticity of substitution of negative 0.14; that is, a doubling of the peak to off-peak price ratio leads to a 14% drop in the corresponding quantity ratio.
- Salt River Project Agricultural Improvement and Power District found that customers saved about 8% on their annual bills; customers that did not save were allowed to drop out of the program after a period.
- Puget Sound discontinued its program. Some thought there was insufficient distinction between peak and off-peak prices to motivate consumers to change their behavior.

Critical peak pricing uses real time pricing at times of extreme peak, and relies on very high critical peak prices. Gulf Power Florida found that significant demand reduction can be achieved with peak pricing. California found customer responsiveness across all groups and geographies.

Real-time pricing links hourly prices to hourly changes in the day-of or day-ahead cost of power. The largest customers in Delaware, Maryland and New Jersey are starting to be placed on day-of mandatory RTP in default-service market designs. Georgia Power found reductions of up to 17% on critical peak days. These savings reduce the amount of costly peak-generation equipment necessary; utilities can pass these savings along to customers.

Demand response program survey results

About 4.8 million customers nationally are enrolled in DLC programs. Baltimore Gas & Electric is among the top 10 entities with 338,568 customers. About 1.4 % of customers in the United States are signed up for TOU tariffs. Again, Baltimore Gas & Electric is among the top ten.

Motivations for using demand response and time-based rates

These include:

- Requirements of EPAct to consider demand response
- Reliability enhancement
- Resource need: demand response can defer construction of generation or distribution resources

- Quick rollout: demand response can be implemented faster than resources can be built
- Regulatory: regulatory directions and initiatives have spurred additional growth of demand response
- Rising energy costs
- Advances in enabling technology
- Lowered utility cost
- Risk management: Customers and LSE's can use demand response to hedge exposure to high prices

Current issues and challenges

Reasons for the low use of demand response programs include:

- Need for investment in meters and other enabling technology.
    - Recent advances have decreased the cost and increased the functionality of these technologies, however.
- Lack of incentives for utilities to promote demand response
    - Demand reductions from demand response programs reduce utility revenues.
        - According to the report, "The disincentive is greater for utilities in restructured states with active ISO demand response programs. Consequently, as representatives for industrial customers have asserted, electric utilities have been reluctant to promote these programs or request some form of lost-revenue recovery."
- Negative impact of industry restructuring on delivery of demand response by utilities.
    - Utilities that have divested generation can only avoid distribution and transmission costs, not the typically higher benefit from avoiding generation costs or procuring power during peak periods.
- Other issues include the difficulty of measuring the demand reduction from programs, slow settlements to demand response providers, customer desire for simplicity, need for simple and fair dynamic pricing, the issue of mandatory

versus voluntary participation, and varying willingness of utilities to work with third party providers.

Demand response activities at the state, regional and Federal level:

The report states that activities at the state level are important to the level of demand response participation achieved. Two state agencies, NYSERDA in New York, and the CEC in California have been leaders in demonstrating demand response. California's Action Plan requires that demand response and energy efficiency be considered before generation additions, and additions begin with renewable energy. The California Commission required that investor owned utilities meet five percent of their load requirements with demand response.

V. Demand response as a resource

The FERC report examines the potential of demand response to serve as a resource and concludes that the current overall potential in the United States is 37,500 MW, about 5% of the projected demand for the summer of 2006. Demand response potential ranges from 3% – 7% in most North American Electric Reliability Council (NERC) regions; the Midwest Reliability Organization (MRO) region is an exception at 20%. Reasons for the high number for the MRO region include:

- Minnesota and Iowa have or have had laws requiring that utilities invest a certain percent of revenue in Demand Side Management programs.
- Utilities in the upper Midwest historically have had rules allowing load management resources to be counted toward meeting resource requirements.
- Customers in the region, especially industrial, may have processes that can be interrupted and thus these customers may be more able to implement demand response programs.

Demand response programs are concentrated in relatively few entities: less than 10 percent of retail entities with demand response programs/tariffs provide almost 75% of the total demand response resource.

VI. Role of demand response in regional planning and operations

The report examines the integration of demand response into regional planning with a special focus on the role of demand response resources in regional planning and operations. Demand response can serve as a local peaking resource and reduce or defer new transmission or distribution facilities. It can also serve as operating reserves. It can increase the utilization of existing transmission, which could provide energy from lower cost generation.

The demand response potential of 37,500 MW nationally is factored into regional resource planning and transmission enhancement either explicitly or implicitly. The sole and explicit use of demand response as an alternative to transmission, however, is rare. Notwithstanding that potential, while PJM, along with the Bonneville Power Administration and the Midwest ISO, reported having policies to consider demand response in transmission planning, no demand response projects have yet resulted from the policies.

Potential for demand response for regional planning

Regional planning at a multistate level is limited but has expanded in recent years with the development of Independent System Operators/Regional Transmission Organizations and other entities pursuing broad planning. Planning is not universal or uniform, however, which presents challenges for effective regional planning. Demand side options have begun to be integrated into the planning process with Integrated Resource Planning.

California requires utilities to include demand side measures directly. The California Public Utility Commission required each utility to meet 3% of its annual system peak demand for 2005 through demand response programs. The percent required increases by 1% each year until 2007. Also, as contracts expire, each utility must use all possible energy efficiency, demand response and distributed resources before issuing a request for supply side resources.

Many other states do not incorporate demand-side measures or demand response in any way. In 5 states, including Delaware, examined in a survey, "demand-side measures were either not required by the state or no incentive existed to include demand-side measures in the integrated resource plan."

In a study for the International Energy Agency, Dan Violette and Rachael Freeman developed a model to examine changes in system costs with and without the inclusion of demand response over 19 years. They found significant differences for plans with demand response resources and those without with regard to hourly costs, capacity charges, and capacity usage. In one simulated case, they found that the addition of demand response reduced the maximum hourly costs on a peak day by more than fifty percent. They found a present value savings in incremental costs of ten percent for the peak-pricing scenario and twenty-three percent for the real-time pricing scenario. The FERC report notes that this study shows that demand response resources can be incorporated directly into integrated resource planning methods.

Transmission planning and operations and demand response

The report finds that while there are well established systems to evaluate proposals for new transmission or generation facilities, no similar process exists for examining demand response solutions. Instead, demand response is typically treated as a solution that may be examined if it is offered by others and if the offering meets criteria that were established based on traditional transmission and generation solutions.

Demand response in transmission planning

The FERC report states that demand response can be used as a direct substitute for transmission enhancement. The report also notes that energy efficiency reduces consumption during all hours and typically reduces the need for transmission. Commission staff, however, concluded that system planners do not typically include new demand response as a potential solution to transmission adequacy problems.

It should be noted that Delmarva does not agree that demand response is a direct substitute for transmission enhancement. Delmarva notes that demand response participation is generally voluntary in nature and therefore does not fulfill the utility's obligation to serve requirements.

Provision of ancillary services by demand response

Some demand response resources are technically superior to generation in supplying spinning reserves because they can curtail consumption faster than generation can increase production. PJM permits demand response to supply spinning reserves.

Regional treatment of demand response

Bonneville Power Administration

BPA owns and operates 15,000 miles of transmission, about 75% of the high voltage grid in the Pacific Northwest. It does not own generation. BPA has a highly visible effort aimed at identifying non-wires alternatives to transmission enhancement. BPA believes non-wires solutions may be a more cost effective solution to meet growing load, and may defer the need to build new transmission facilities. "Non-wires solutions are attractive because transmission constraints often occur 40 hours or less per year.... BPA has committed to study non-wires solutions before deciding to build any transmission enhancements." BPA's focus is on deferring new transmission, rather than looking at demand response as a permanent resource. Even a deferral can be valuable. A demand response project that defers a $60 million transmission project for three years, for example, would have a present value of $11 million, based on a 7% interest rate.

BPA formed a Non-Wires Solutions Round Table to obtain opinions from a diverse set of stakeholders. Institutional barriers identified by the Round Table include issues such as:

- "Lost utility revenue—utilities are reluctant to pursue demand response when it may reduce sales and revenue"
- Lack of incentive for accurate forecasting—high forecasts can justify additional transmission, making it more difficult for demand response solutions to be adopted
- Lack of transparency in transmission planning

Currently BPA demand response programs are in the pilot stage. The first full initiative to actually defer a transmission project may happen in late 2006.

California ISO

As discussed above, California expects demand response to meet 5% of system peak by 2007.

PJM Interconnection

According to the report, demand response is implicitly included in PJM regional transmission planning a modifier to forecast load. As of May 1, 2006, PJM became the first RTO to allow demand response to participate in ancillary service markets. PJM has identified barriers to incorporating demand response into PJM transmission planning and operations:

- Lack of widespread use of hourly and sub-hourly metering, required to accurately measure demand response, and
- Lack of good long-term demand response forecasting

Florida Reliability Coordinating Council

Florida Reliability Coordinating Council (FRCC) is the regional reliability council for the state of Florida. While the potential contribution of demand response in Florida is 7%, the Florida PUC has been reevaluating the cost-effectiveness of demand-side management and has been reducing the rebates offered to consumers. As a result, the amount of available demand-side management capability has been decreasing, transmission planners do not consider demand response, and the demand forecast is not reduced be the amount of expected demand response. Nevertheless, there is still considerable demand response capability in Florida. Progress Energy Florida, for example, has 1000 MW of peak load reduction and 2000 MW of emergency response available within two seconds to one minute. FRCC, however, does not qualify this resource as spinning reserve.

International examples

- In the Nordic countries, Nordel, the regional transmission operator, "regards demand response as critical to supporting reliability but it does not implement demand response programs itself as this is done by the individual countries."
- In Australia, peak demand is 31,000 MW. Energy prices typically are under A$40/MWh but can go as high as A$10,000/MWh during system emergencies. Demand response supports deferral of capital expenditures for load-growth related network expansion.

- The New South Wales DM Code of Practice requires distribution Network Service Providers to exhaust demand-side management alternatives before building new transmission to meet load growth needs.

Examples of demand response projects

The following examples illustrate steps taken to use demand response as an alternative to transmission.

LIPA Edge: The LIPA Edge project of the Long Island Power Authority currently controls 25,000 residential and 5,000 small commercial units; the units provide 36 MW of peak load reduction. As a result of additional analysis, it is estimated that spinning reserves capacity is now likely over 100 MW which could provide a significant benefit to capacity constrained Long Island.

Southern California Edison Feeder Relief: Southern California Edison (SCE) conducted a project in the summer of 2006 with these objectives: demonstrate that the available MW demand response of a specific circuit can be predicted with a 90 % statistical confidence and demonstrate that the load can be curtailed reliably and quickly when a dispatch signal is issued. The load shed is expected to begin within ten seconds of the signal and be fully implemented within two minutes.

Consolidated Edison: Consolidated Edison is seeking proposals for demand side management as an alternative to transmission and distribution expansion. Consolidated Edison issued an RFP in April 2006 seeking at least 123 MW of demand side management to targeted areas of New York City and Westchester County in order to defer transmission and distribution investment. Clean distributed generation and energy efficiency measures may be proposed.

Concerns and obstacles

Obstacles to greater use of demand response in transmission planning and operations include:

- Lack of uniform treatment of demand response
- Perceived temporary nature of demand response

    - When demand response is considered as an alternative to new transmission, it is typically considered as a deferral rather than as permanent solution.
- Regulatory treatment of transmission and demand response costs
    - Transmission is generally treated as a regulated asset; once its cost is in the rate base, its costs are fully covered. Demand response is not usually treated as a regulated capital resource placed in a rate base. Demand response may be cheaper overall, but once transmission cost is in the rate base, it may appear to be lower cost.
    - Reliability regions and ISOs are typically barred from actively developing demand side resources as alternatives to transmission enhancement.
- Reliability of statistical demand response
    - While some argue that demand response is not as reliable or certain as generation response, according to the report, there is good reason to believe that the reliability of the response from aggregating small loads is actually better than the reliability of response from large generators.
- Capacity credit: demand response programs are sometimes disadvantaged in formal capacity markets. For example, some markets impose an artificial requirement that response must be available 24 hours a day, all season long. Demand response may not meet that requirement even though it can reliably produce capacity at times of need.

Steps that could be taken to ensure that demand response receives equitable treatment in regional transmission planning and operations

Commission staff has identified the following steps which transmission planners and state and Federal regulators should consider ensuring equitable treatment in transmission planning and operations:

- Assure that demand response capabilities and characteristics are properly recognized
- Assure that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need

- Accommodate the inherent characteristics of demand response resources
- Allow appropriately designed demand response to provide all ancillary services
- Allow for the consideration of demand response alternatives for all transmission enhancement proposals
- When appropriate, treat demand response as a permanent solution, similar to transmission enhancements

VII. Regulatory barriers

The report identifies a number of regulatory barriers to improved customer participation in demand response programs as described below.

Disconnect between retail and wholesale markets

According to the report, the most frequently mentioned regulatory barrier is the disconnect between fixed retail prices and fluctuating wholesale prices. Placing even a small percentage of customers on tariffs based on time-based rates can result in a more efficient allocation of resources. Further, because the price of energy delivered during peak times is greater than in non-peak times, average pricing results in an income transfer from customers who use a lower proportion of their energy during low peak to those who use a high proportion during peak.

Utility disincentives associated with offering demand response

It is possible that demand response would decrease utility earnings in the short-term and this possibility can serve as a disincentive for utilities to actively promote demand response. Restructuring has added additional disincentives for distribution utilities. Distribution utilities would not receive a large proportion of the pricing benefits of demand response programs.

Policies to address the utility disincentives include:

- Remove disincentives by breaking the link between profits and sales volume
    - Decoupling policies are being actively examined in state proceedings and have been implemented in California and Oregon.

- Other states such as New York and Connecticut rejected rate decoupling, noting the negative impact that large revenue accruals can have on rate stability.
- Decoupling policies are being discussed at MADRI.

- Recover costs: give utilities a reasonable opportunity to recover the costs of implementing demand response programs
- Reward performance: Policies can include incentives for implementing high-performance demand response programs.

Cost recovery and incentives for enabling technologies

Utilities are reluctant to invest in enabling technologies unless the business case for the investments is sufficiently positive. They also are concerned about the possibility of investments becoming stranded costs. According to the report, recovery of at least part of the utility investment either through expensing or rate-basing may be necessary. Returns from this investment need to be at least commensurate with returns utilities can get from their generation and transmission assets. Utilities are also concerned that the economic life of equipment match its accounting life; equipment should be amortized or depreciated over its economic life.

Need for additional research on cost-effectiveness and measurement of reductions

The ability to forecast and understand how greater price responsiveness will affect load shapes, load growth, and resource needs is limited. Further, most of the tests for cost effectiveness were designed to measure programs by vertically-integrated utilities in non-restructured environments. Other costs and benefits such as customer and societal impacts are not included. There is also no consistency in the evaluation methodologies that have been used by ISOs on their programs. Lastly, whether or not operational benefits such as remote shut-off are included in the cost effectiveness evaluation can have a significant impact on the payback period for equipment such as advanced meters. California is working to develop an integrated efficiency and demand response framework.

State level barriers to greater demand response

California and New York limit the ability to introduce new time-based rates, especially real time pricing. One commentator interpreted Delaware's HB 6 to contain similar restrictions.

Specific retail and wholesale rules that limit demand response

Standard procedure in the ISOs is to complete final settlement for positions between 60 to 90 days after the close of the real-time or day-ahead market. Third party aggregators complain that this settlement provision delays when they can provide customers payment for their actions. Provisions in the PJM tariff also make it difficult for third-party aggregators to provide the ISO an accounting of when curtailments occurred within a set time period.

Insufficient market transparency and access to data

Lack of access to data has been identified as a barrier to demand response. As one commentator noted, "If you want to move toward having customers being exposed to prices, you have to understand what's happening in the market, and, right now, we have very little information about what's happening among retailers in this area." Customer response to time-varying prices has the most impact when customers can see the result of their actions in real-time or near real-time.

Better coordination of Federal-state jurisdiction affecting demand response

Some commentators suggested that confusion over the scope of demand response in wholesale markets has limited the full potential of demand response, and that greater clarity and coordination between wholesale and state programs is needed.

VIII. Conclusion

Staff encourages states to continue to consider ways to actively encourage demand response at the retail level, and recommends that the Commission and states work cooperatively in finding demand response solutions. Staff also recommends the Commission explore how to better accommodate demand response in wholesale markets, how to coordinate with utilities, states and others on demand response in the wholesale and retail markets, and consider specific proposals, including how to eliminate regulatory barriers to improved participation in demand response.

D

Appendix D – Delaware Smart Meter Pilot Program

In response to the Settlement Agreement, Delmarva representatives met on numerous occasions with the Commission Staff, Commission Staff, and representatives of the Public Advocate to discuss a possible Delaware smart metering pilot. A summary of these activities is presented below.

April 2003

Delmarva representatives met with the Commission Staff to discuss smart metering pilot program expectations and options. The parties agreed at that time to continue meeting to develop plans for the pilot.

June 2003

Delmarva representatives met with the Commission Staff and the Public Advocate to discuss the design of a possible smart meter pilot. During the meeting, participants agreed to evaluate prepaid metering and an expanded time-of-use rate offering. Under this proposal, sophisticated metering would be installed that would provide participants with additional billing data.

August 2003

The Commission Staff requested Delmarva to provide additional information regarding more sophisticated meters and different rate designs that could be supported.

October 2003

Delmarva representatives shared information on time-of-use and prepaid metering with the Commission Staff and representatives of the Public Advocate. Staff stated during the meeting that they were aware that the costs associated with the installation of a real time metering system were beyond the intent of the merger Settlement Agreement. Therefore, parties agreed that if any smart metering system were installed, that a cost recovery mechanism would need to be established.

November 2003

Delmarva representatives, Commission Staff, and representatives of the Public Advocate met to discuss development of a smart metering pilot proposal to be submitted to the Commission for its consideration. Commission Staff indicated that they recognized that a cost recovery mechanism must be established for any pilot program, as none was provided in the Settlement Agreement.

April 2004

Delmarva prepared and submitted a residential smart meter pilot program to the Staff for its consideration.

May 2004

Delmarva met with the Commission Staff and the Public Advocate to discuss proposed modifications to the Company's proposal. As a result of this meeting, minor modifications were made to the April 2004 proposal.

June 2004

Delmarva, the Commission Staff, and the Public Advocate drafted a residential smart meter pilot program plan. A summary of the proposed pilot program is listed below:

- Randomly selected residential customers invited to participate (opt-in).
- Additional conservation educational material provided to half of the participants.
- On-peak hours set at 5 to 6 hours per day.
- Rates designed to be revenue neutral and a ratio of 4.2:1 on-peak to off-peak was agreed upon.
- In-home display unit to provide participants with energy consumption information.
- Monthly bill comparison of new time-of-use rate compared to what customer would have paid under prior rate.
- Customer survey planned
- Analysis planned.

Preliminary pilot timeline, assuming July 2004 Commission approval:

- September 2004 – Design of promotional materials and mailings.
- October/November 2004 – Participant recruitment.
- December 2004 – Participant education and equipment installation.
- January-December 2005 – Billing under proposed pilot rates.
- January-March 2006 – Evaluation work.
- March 2006 – Develop recommendations for future SOS customers.

First Quarter 2005

Commission Staff recommend that Delaware smart meter pilot recommendations be incorporated into Delaware SOS and base rate case discussions.

March 2005

Commission issues Order No. 6598, Docket 04-391 on March 22, 2005. Section F.41 specified DE SOS Phase 1 requirements. Advanced metering/energy efficiency program was characterized as "inactive." Order noted that if the pilot program is successful, that information should be included into the future SOS procurement process.

April 2005

Pepco Holdings, Inc Executive Vice President Tom Shaw and Delmarva President Gary Stockbridge present "State of the Company" to the Commission, including a brief discussion of the Company's advanced metering strategy.

July 2005

Itron, an Advanced Meter Infrastructure vendor, presents an overview of advanced metering to the Commission Staff.

October 2005

Commission issues Order No. 6490, Docket 04-391 on October 19, 2004, related to SOS Phase 2 requirements, but the Order does not discuss the proposed smart meter pilot program.

January 2006

Commission Staff analyst Heidi Wagner becomes lead of the smart meter pilot project on behalf of the Commission. Former Commission Staff project lead Janis Dillard noted during a meeting that the pilot would be deferred pending resolution of various SOS issues and also noted that Delmarva and the Commission Staff had worked well together on the development of the pilot proposal.

May 2006

DE Docket No. 57 Working Group Established by Commission Order No. 6912 to develop recommendations regarding advanced metering for the Commission's consideration.